# Jumpstarting commercial-scale $CO_2$ capture and storage with ethylene production and enhanced oil recovery in the US Gulf

Middleton, Richard S.
Levine, Jonathan
Bielicki, Jeffrey
Carey, James William
Viswanathan, Hari S.
Stauffer, Philip H.



**To be published in:** Greenhouse Gases: Science and Technology

**DOI to publisher's version:** 10.1002/ghg.1490

**Title**: Jumpstarting commercial-scale $CO_2$ capture and storage with ethylene production and enhanced oil recovery in the U.S. Gulf

**Authors:** Richard S. Middleton, Jonathan S. Levine, Jeffrey M. Bielicki, Hari S. Viswanathan, J. William Carey, Philip H. Stauffer

## Abstract

$CO_2$ capture, utilization, and storage (CCUS) technology has yet to be widely deployed at a commercial scale despite multiple high-profile demonstration projects. We suggest that developing a large-scale, visible, and financially viable CCUS network could potentially overcome many barriers to deployment and jumpstart commercial-scale CCUS. To date, substantial effort has focused on technology development to reduce the costs of $CO_2$ capture from coal-fired power plants. Here, we propose that near-term investment could focus on implementing $CO_2$ capture on facilities that produce high-value chemicals/products. These facilities can absorb the expected impact of the marginal increase in the cost of production on the price of their product, due to the addition of $CO_2$ capture, more than coal-fired power plants. A financially viable demonstration of a large-scale CCUS network requires offsetting the costs of $CO_2$ capture by using the $CO_2$ as an input to the production of market-viable products. We demonstrate this alternative development path with the example of an integrated CCUS system where $CO_2$ is captured from ethylene producers and used for enhanced oil recovery in the U.S. Gulf Coast region.

## Introduction

> *"CCS is caught in a vicious cycle… Firms will not invest in CCS because it is financially risky; it is financially risky because public acceptance is low and there are big hurdles to large-scale deployment; and public acceptance is low because there is so little experience with CCS at a large scale." – William Nordhaus*[1]

$CO_2$ capture, utilization, and storage (CCUS) is a climate mitigation technology that can reduce industrial greenhouse gas (GHG) emissions by thousands of megatonnes of $CO_2$ annually (1000s $MtCO_2$/yr).[2] CCUS involves capturing and compressing $CO_2$ from stationary sources (e.g., coal-fired power plants), transporting the $CO_2$ in dedicated pipelines, and injecting and storing the $CO_2$ in geologic reservoirs (e.g., deep saline aquifers) and perhaps using that $CO_2$ to produce marketable products.[3, 4] CCUS is an essential component of the portfolio of approaches needed to reduce $CO_2$ emissions and stabilize the concentration of $CO_2$ in the atmosphere.[5, 6] At present, 68% of the electricity generated in the United States results from burning fossil fuels, more than half of which uses coal—the most $CO_2$ intensive source—as the primary energy resource.[7, 8] Implementing CCUS could enable a gradual transition to energy sources that emit less $CO_2$ per unit of energy while continuing to leverage the useful lifetime of existing energy infrastructure. CCUS is also pertinent for developing countries, such as China and India, that have or plan to rapidly expand their fleet of coal-fired power plants that will continue to emit $CO_2$ for many decades.[9] Ultimately, CCUS must be deployed at a "commercial scale," where many $CO_2$ sources (including hundreds of power plants) and geologic reservoirs are connected by an extensive network of dedicated pipelines.[10] (Several examples of individual power plants connected to geologic reservoirs already exist, including the Boundary Dam[11, 12] and W.A. Parish[13, 14] generating stations, but not multiple large power plants in a single network.)

Technologies for each step in the CCUS supply chain—$CO_2$ capture, transport, and injection/storage—have been implemented at commercial scale for several decades,[15] and multiple large (≥1 $MtCO_2$/yr) CCUS projects around the world are successfully demonstrating the performance of these technologies. Present projects include $CO_2$ capture from a range of industrial sources, including natural gas processing or stripping (e.g., Shute Creek, Wyoming;[16] Sleipner Vest, Norway;[17] Gorgon, Australia[18]), coal gasification (e.g., Beulah, North Dakota[19]), and biorefineries/ethanol production (e.g., Decatur, Illinois[20]). Five of the nine large operational integrated CCUS systems in the world are in the United States[21] (Figure 1), as well as the capture (Beulah, ND) for the Canadian storage project. But despite the importance and potential of CCUS, and the safe demonstration of individual CCUS projects, commercial-scale deployment of CCUS has not yet occurred.

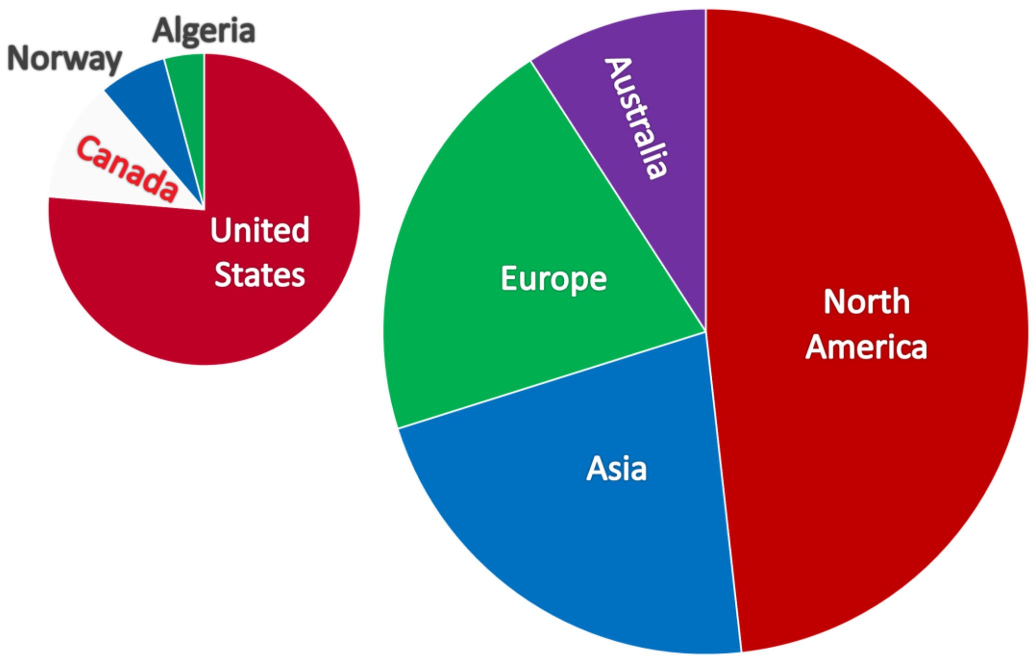


*Figure 1: Distribution of currently operational (left, 24.08 $MtCO_2$/yr) and planned (right, 99.54 $MtCO_2$/yr) integrated CCS projects as of June 2013. Projects only include large coal (≥ 0.8 $MtCO_2$/yr) and large industrial (≥ 0.4 $MtCO_2$/yr) projects. The operational project in Algeria—In Salah—is now inactive.*

Numerous barriers to CCUS deployment exist, including interlinked issues such as costs, public awareness and acceptance,[22] regulation and permitting,[15] and operational experience with large integrated CCUS systems.[15] To initiate near-term commercial-scale deployment of CCUS, a development path for an integrated system that handles 50-100 $MtCO_2$/yr is perhaps needed—roughly an order of magnitude larger than the 10 $MtCO_2$/yr emitted from a large coal-fired power plant. Accelerating CCUS deployment could be achieved by developing a highly visible and economically viable demonstration of a commercial-scale CCUS system that integrates multiple $CO_2$ sources and reservoirs. Implementing $CO_2$ capture increases general production costs; for coal-fired power plants this could result in a doubling of electricity prices for consumers. We suggest that systems that use $CO_2$ captured from facilities that produce high-value chemicals/products (HVCPs), such as ethanol or iron/steel production, can better absorb the expected impact on the price of their products.[23] Using this HVCP $CO_2$ to produce a marketable commodity further adds economic viability. Near-term pathways that focus on the development of such an integrated system would complement present investment approaches, which have focused on developing and demonstrating *new* technologies for two of the three stages in the CCUS supply chain: $CO_2$ capture and $CO_2$ storage. Our proposed pathway focuses on market-viable $CO_2$ capture from HCVP facilities—some of which are in industries that already provide $CO_2$ for use elsewhere—and the implementation of pipeline transportation like that which already exists for $CO_2$-based enhanced oil recovery ($CO_2$-EOR). We demonstrate our approach in a case study using *existing* technology to capture $CO_2$ from ethylene producers as well as for $CO_2$-EOR in the U.S. Gulf Coast region. Our perspective is to provide an overview of near-term market-viable opportunities to establish the operation of CCUS, as an integrated system, while other pathways for technology development are being pursued.

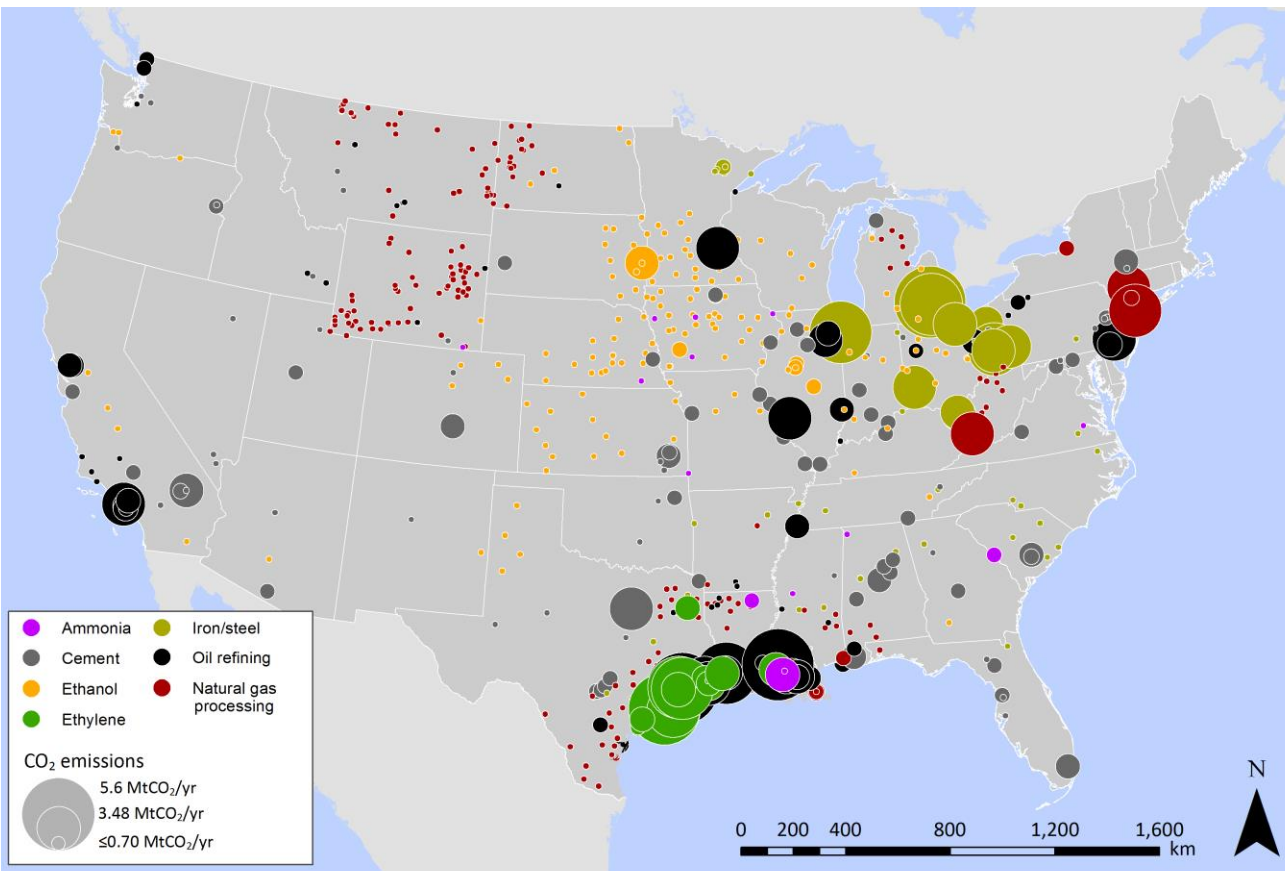


*Figure 2: Spatial distribution of HVCPs in the United States.*[24]

*Table 1: Major sources of $CO_2$ in the US including production amounts, costs, $CO_2$ emissions, and impact of $CO_2$ capture. The table is based on major products highlighted in the NATCARB database.[24] Entries without a clear distinction in the NATCARB database (e.g., mining, general manufacturing, and agriculture)—a total of 30* $MtCO_2$*/yr emissions—are omitted from the table. Missing entries in the table denotes values that do not exist in the public domain.*

| Product | Annual U.S. production | Representative cost (electricity) or price | Emissions ($MtCO_2$/yr) | Number of sources | | Clustering (km from centroid[a]) | Capture cost ($/t$CO_2$) | Cost/price increase (%) |
|---|---|---|---|---|---|---|---|---|
| | | | | Total | >1Mt $CO_2$/yr | | | |
| Electricity (fossil/biomass)[b] | 2783.3 TWh[25] | - | 2394.4[25] | 3314[25] | 473[25] | - | - | - |
| Coal | 1784 TWh[25] | $62-141/MWh[26] | 1912.2[25] | 560[25] | 308[25] | 835 | 29-51[27] | 61-76[28] |
| Natural Gas | 907 TWh[25] | $61-89/MWh[26] | 431.7[25] | 1416[25] | 157[25] | 1113 | 37-74[27] | 37-57[29] |
| Biomass | 68 TWh[25] | $87-116/MWh[26] | 26.7[25] | 560[25] | 2[25] | 635 | - | 42[30] |
| Oil & Petroleum Coke | 25 TWh[25] | $68/MWh[30] [c] | 23.9[25] | 778[25] | 6[25] | 704 | - | 66[30] |
| Oil Refining[d] | 15 MMbbl/d[31] | $92.02-104.67/bbl[e] | 172.5[24] | 308[24] | 62[24] | 1346 | 19-96[2] | 1-6[28] |
| Cement | 67.9 Mt[32] | $90/t[32] | 85.7[24] | 111[24] | 30[24] | 1258 | 46-80[2, 28] | 39-52[28] |
| Iron/Steel | 113.5 Mt[32] | $126/t[32] [f] | 76.3[24] | 88[24] | 16[24] | 434 | >54[28] | 10-14[28] |
| Ethylene | 27.6 Mt[33] | $1040/t[34] | 50.1[24] | 25[24] | 20[24] | 124[g] | 35-55 | 3-11 |
| Ethanol | 13.9 Bgal[35] | $1.95-2.55/gal[36] | 49.3[24] | 173[24] | 3[24] | 662 | 6-12[28] | 1-2[h] |
| Pulp/Paper/Wood | 75.3 Mt[32] [i] | - | 22.4[24] | 78[24] | 6[24] | 490 | 6-12[28] | - |
| Natural Gas Processing | 16.3 Tcf[37] | $3.35/MCF[38] [j] | 18.4[24] | 144[24] | 1[24] | 350 | 16-21[28] | 1[28] |
| Ammonia/Fertilizer | 9.4 Mt[32] [k] | $585/t[32] | 10.1[24] | 21[24] | 2[24] | 381 | 10-20[28] | 3[28] |
| Soda | 10.7 Mt[32] | $147/t[32] | 4.2[24] | 5[24] | 2[24] | 7 | - | - |
| Lime | 19.1 Mt[32] | $112/t[32] | 3.8[24] | 10[24] | 1[24] | 621 | - | - |

[a] Clustering is calculated as the average distance between each $CO_2$ source and the centroid of all those sources from NATCARB.
[b] Includes "other" fossil fuels such as coke oven gas and tire-derived fuel.
[c] Inflated from 2006 to 2012 using CPI calculator but not changes due to oil price.
[d] Refining to gasoline/diesel.
[e] WTI monthly spot price range between January and July 2013 - http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm.
[f] Price for steel.
[g] Excludes one ethylene source in Pennsylvania.
[h] Assumes capturable $CO_2$ of 2.8 kg per gallon and $12/tco2 capture cost.
[i] Paper and board.
[j] Wellhead price.
[k] Tonnes of nitrogen content.

## $CO_2$ capture from High Value Chemicals and Products (HVCPs) Production

Much of the effort for developing $CO_2$ capture technology has focused on fossil-fueled power plants, in part because of the size of the installed base. The $CO_2$ emissions from power plants form the majority of stationary $CO_2$ emissions in the United States.[24] In addition, $CO_2$ capture costs are estimated to comprise up to 90% of the CCUS supply chain costs, and $CO_2$ capture on fossil fuel power plants can increase the cost of production 50-100%, from $31-51/MWh to $43-72/MWh for natural gas power plants and $43-52/MWh to $62-86/MWh for coal-fired plants[27] (Table 1). The potential doubling of electricity prices has led public utilities commissions to reject CCUS plans due to unacceptable increases in the rate that consumers would have to pay.[39, 40]

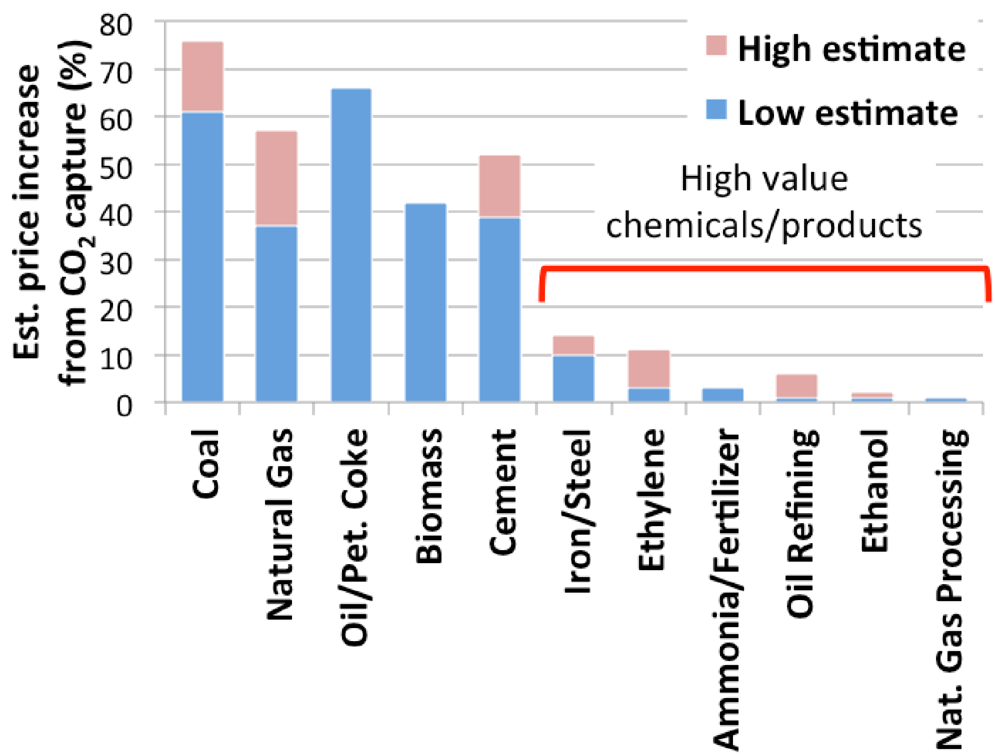


*Figure 3: Estimated relative price increases due to $CO_2$ capture (last column in Table 1) are much lower for high value chemicals and products relative to fossil-fuel power plants.*

As an alternative, $CO_2$ that is emitted from facilities that produce HVCPs could be attractive candidates for $CO_2$ capture. Four of these industries—oil refining, iron/steel production, ethylene manufacture, and ethanol production—each emit at least 50 $MtCO_2$/yr (Table 1).[24] Collectively HVCP industries emit 360 $MtCO_2$/yr, which is roughly the same amount of $CO_2$ emitted by natural gas power plants. These HVCP facilities are located broadly throughout much of the non-mountainous portions of the United States (Figure 2). Most importantly, the estimated marginal increase in the cost of production is much lower for HVCPs than for power plants. In a competitive industry, where profit-maximizing firms should seek to set price equal to marginal cost, the estimated proportional increases in price for HCVP facilities range between 1-15%, which is substantially less than the estimated increases in the price of fossil-based electricity (Table 1, Figure 3).

HVCPs also enable targeted $CO_2$ capture to stimulate large-scale CCS. For example, as Figure 2 shows, ethanol facilities are distributed over the U.S. Midwest. These facilities currently emit around 50 $MtCO_2$/yr in aggregate, which is an amount sufficient enough to be the basis for a large-scale CCUS network without oversupplying $CO_2$. As a consequence, there would likely be a minimal impact on marginal price of $CO_2$ supplied for EOR. Facilities in other HVCP industries, such as ethylene manufacturing, are larger in size and more clustered in location, which provides logistical advantages for the establishment of an integrated CCUS system. For the remainder of this paper we use $CO_2$ capture from ethylene production facilities as one example of how an integrated network using $CO_2$ captured from HCVPs could stimulate commercial-scale CCUS.

## Ethylene manufacture and $CO_2$ capture

Ethylene is used throughout the petrochemical industry. Almost 60% of the supply devoted to producing polyethylene for products such as packaging and plastic bags.[41] Ethylene is manufactured by steam cracking hydrocarbons including ethane, naphtha, propane, and butane.[42] The energy necessary for this cracking is provided by burning natural gas and other residual gases from the cracking process.[43] Worldwide ethylene production is greater than 140 Mt/yr, with production concentrated in three countries: the United States (27.6 Mt/yr)[44], Saudi Arabia (13.2 Mt/yr), and China (13.0 Mt/yr)[33] (Figure 4). In the United States, ethylene facilities are clustered in the Texas and Louisiana Gulf Coast region (Figure 5), largely due to feedstock availability. These U.S. facilities emit approximately 50 $MtCO_2$/yr.[24]

We are not aware of literature that estimates $CO_2$ capture costs specifically for ethylene facilities. Since a detailed facility-level systems analysis is outside the scope of this paper, we approximate these costs by the similarity of the flue gas $CO_2$ concentration and pressure to that of coal-fired power plants (12% vs. 12-15% by volume, 1 bar[2, 45]). As a result, $CO_2$ capture costs for ethylene facilities are broadly similar to those for coal-fired power plants, approximately \$35-\$55/$tCO_2$.[27] Manufacturing one tonne of ethylene produces between 1 $tCO_2$ (ethane feedstock) to 2 $tCO_2$ (naphtha feedstock)[46], and each tonne of $CO_2$ costs \$35-\$55/$tCO_2$ to capture. Ethylene prices reached \$1500-\$1800/t between 2008 and 2012, and typically are around \$1000/t.[47] At a lower price of \$1000/t, these increases in costs translate into an additional \$35-\$110/t of ethylene. Assuming that ethylene markets are competitive and therefore priced at their marginal cost, $CO_2$ capture would add 3.5 to 11% to the price of ethylene. Consequently, $CO_2$ capture from ethylene production results in a much lower increase in price than for fossil fueled electricity generation. For example, electricity prices from natural gas and coal are expected to increase prices by 55-70% (Table 1).

From the market perspective, individual facilities and their owners should be concerned about the competitiveness of their products. The modest estimated increase in costs when $CO_2$ is captured is only a small portion of the price of the ethylene from facilities that do not capture $CO_2$. As a result, $CO_2$-capturing ethylene facilities should not be at a competitive disadvantage. In addition, ethylene is typically used as an input to other processes and products within complex supply chains. The price elasticity of demand for ethylene is low because there are no feasible substitutes, and as a result the marginal increase in cost is unlikely to affect the margins of other producers and suppliers. Further, cost increases for inputs will pass through these supply chains, but demand elasticities and efficiencies throughout the supply chain between the ethylene manufacturer and the public will mitigate this increase to the public. As a result, the public is unlikely to directly experience increased costs, which is in sharp contrast to electric utilities that will visibly pass on costs to consumers in their electricity bills.

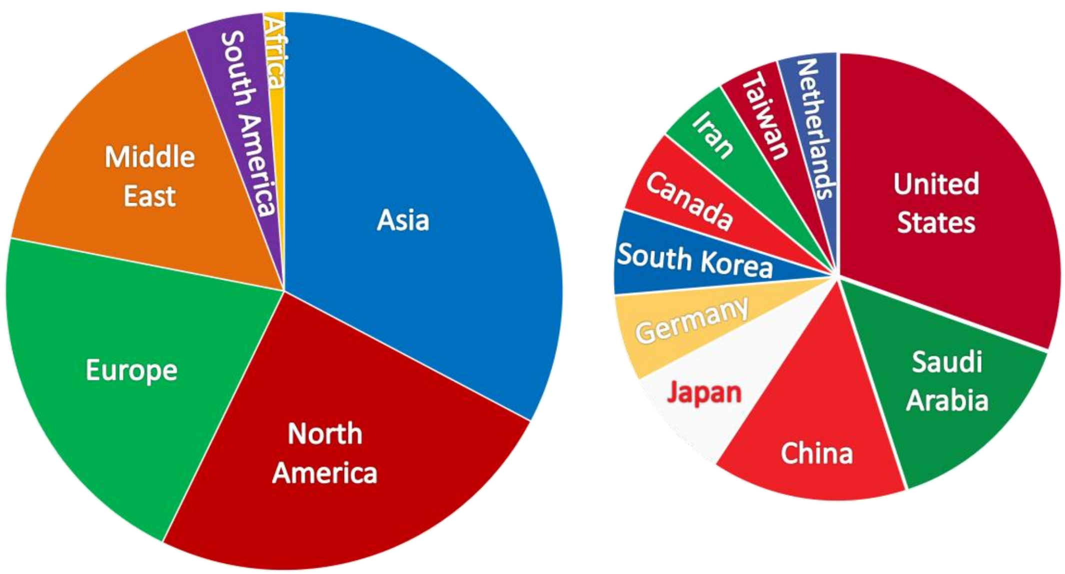


*Figure 4: Distribution of ethylene manufacturing by continent (left, 141 Mt/yr) and top ten producing countries (right, 91 Mt/yr).*

In addition to the modest increase in costs and expected prices due to $CO_2$ capture, ethylene manufacturing facilities are more clustered than any other major $CO_2$-emitting industry, and 20 out of 25 sources in the region emit >1 $MtCO_2$/yr, a higher proportion than any other major $CO_2$ emitting industry (Table 1). Assuming that fixed and operating costs do not exhibit increasing marginal costs with increased facility size, these economies of scale suggest that larger sources are more attractive candidates for $CO_2$ capture than are smaller sources. The combination of substantial $CO_2$ emissions (50 $MtCO_2$/yr), a small increase in price, and sources that are clustered together, make $CO_2$ capture from the U.S. ethylene industry a promising avenue for stimulating regional-scale $CO_2$ capture.

## $CO_2$-Enhanced oil recovery ($CO_2$-EOR)

$CO_2$-EOR produces oil by injecting large volumes of $CO_2$ and water into depleted oil reservoirs. This tertiary production technique typically produces an additional 4-15% of the original oil in place (OOIP) on top of primary and secondary techniques that produce about 30-35% of the OOIP.[48] $CO_2$-EOR in the United States accounts for 46% of the oil produced by EOR processes.[49] Next generation $CO_2$-EOR technologies could recover 22% or more of the OOIP, resulting in production of up to 60% of the OOIP by primary, secondary, and tertiary means.[48] At present, about 4% of domestic U.S. oil production is by $CO_2$-EOR.[48] In 2012, there were 120 active $CO_2$-EOR projects in the United States that produced more than 352,000 bbl/d of oil[49] and purchased about 60 $MtCO_2$/yr.[50] Some of the $CO_2$ that is injected for $CO_2$-EOR will be produced with the oil, but most of this produced $CO_2$ is recycled and re-injected. As a consequence, the amount of $CO_2$ that is purchased ends up being stored in the reservoir, even if it is re-used multiple times.

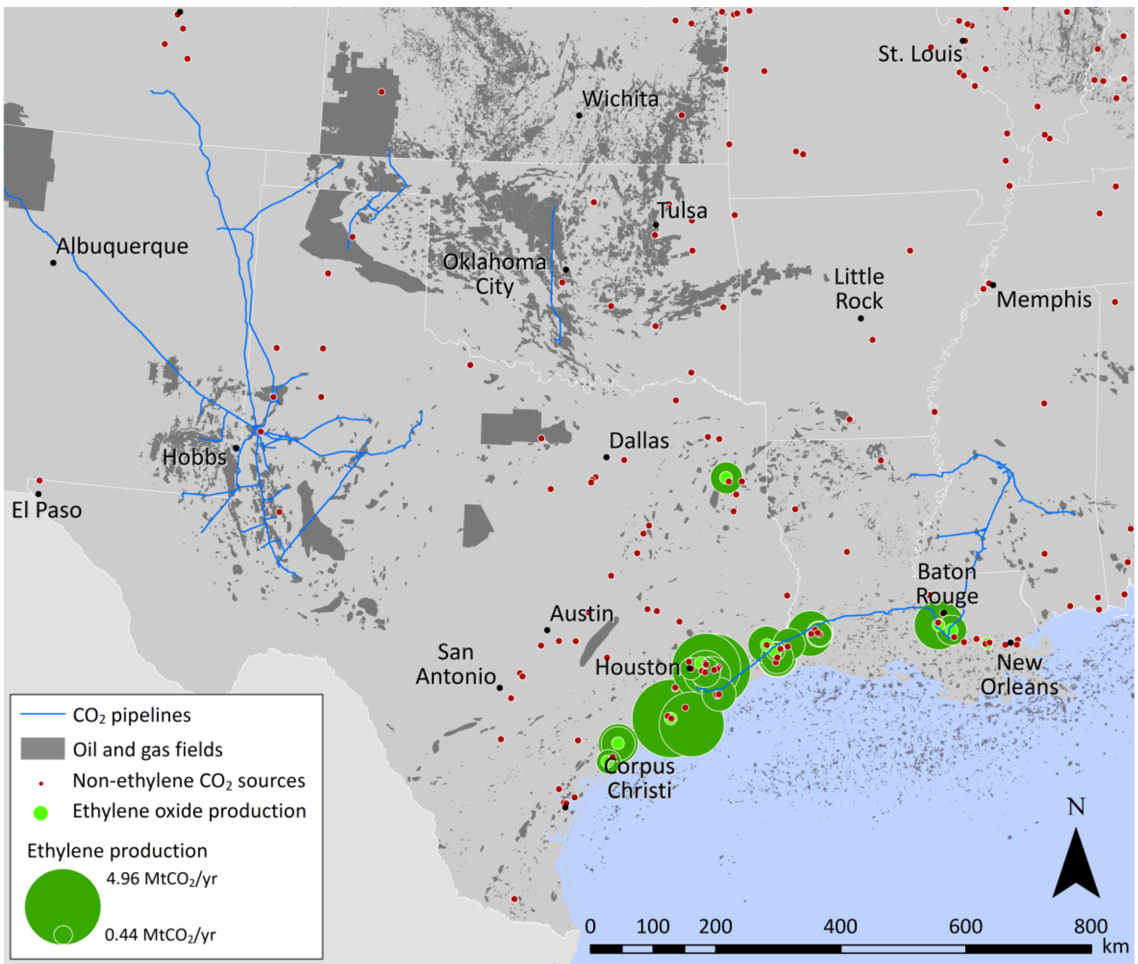


*Figure 5: Ethylene and ethylene oxide production, major non-ethylene sources of $CO_2$, existing $CO_2$ pipeline transportation network, and oil & gas fields in the western U.S. Gulf Coast region and surrounding areas.*[51]

The key goal of CCUS is to reduce the amount of $CO_2$ emitted to the atmosphere. However, about three quarters of the $CO_2$ used for $CO_2$-EOR is extracted from natural geologic deposits[50] in a process that relocates naturally occurring $CO_2$ from one subsurface location—where it would have remained isolated from the atmosphere indefinitely—to another. Only one quarter of the $CO_2$ that is used for EOR is captured from industrial sources. Using this "byproduct" $CO_2$, which is normally vented to the atmosphere, instead of "extracted" $CO_2$, is the only way that EOR can reduce net $CO_2$ emissions to the atmosphere on a life cycle basis.[50] The majority of the byproduct $CO_2$ used for EOR is sourced from natural gas processing facilities where $CO_2$ is be stripped from produced gas in order to meet pipeline specifications. Using byproduct $CO_2$ can reduce the net amount of $CO_2$ emitted to the atmosphere.[52] For example, byproduct $CO_2$-EOR can reduce the wells-to-wheels emissions compared with conventional oil production by 25-60%.[53]

Purchase prices for EOR-ready $CO_2$ (i.e., including $CO_2$ capture, purification, compression, and delivery/transportation costs) are \$28 to \$52/t$CO_2$ for oil prices of \$60 to \$110/bbl.[54] Oil prices below \$60/bbl will likely have a commensurate drop in $CO_2$ prices, though long-term crude prices are likely to substantially rebound. One common $CO_2$ price relationship suggests EOR operators are prepared to pay 2.5% (in \$/Mcf) of the Western Texas Intermediate (WTI) oil price (\$/bbl);[55] at an oil price of \$100/bbl this is equivalent to \$47/t$CO_2$. At this price, $CO_2$-EOR offers a substantial incentive for high-purity $CO_2$ sources to capture their emissions (e.g., ethylene oxide, ammonia, and biorefineries with capture and compression costs of less than \$20/t$CO_2$) as well as significantly offsetting costs for more expensive capture technologies (e.g., fossil fuel power plants and oil refineries). And because EOR operators can sign up to 20 year $CO_2$ supply contracts,[55] $CO_2$-EOR has the potential to reduce $CO_2$ emissions over the medium to long term.

With present technology, $CO_2$-EOR may reduce the $CO_2$ footprint of U.S. transportation fuel in the short and medium term, assuming that $CO_2$-EOR gasoline is displacing conventional gasoline. For example, the one-third reduction in life cycle $CO_2$ emissions through $CO_2$-EOR relative to conventional gasoline[53] is approximately the same as that from compressed natural gas (CNG) vehicles (~6-30% reduction[56-58]) and first-generation biofuels (~3-20% reduction,[59, 60]). Similarly, the $CO_2$-EOR gasoline footprint compares well with the one-third reduction in $CO_2$ emissions by hybrid electric vehicles (HEVs)[61] and plug-in hybrid electric vehicles (PHEVs) using a typical balance of electricity sources in the United States.[61]

With larger quantities of cost-effective $CO_2$ from HVCPs and the appropriate market incentives, greater quantities of $CO_2$ could be used in the EOR process. At present, $CO_2$ is an input to EOR operations that optimize for oil production, but it is possible to co-optimize $CO_2$ storage and oil production if the incentives are in place to value sequestering $CO_2$ from the atmosphere.[62] A typical $CO_2$-EOR operation uses roughly equal amounts of $CO_2$ and water whereas a pure $CO_2$ flood can increase production use and store larger quantities of $CO_2$.[62-64] Furthermore, primary and secondary oil production techniques can reduce ultimate recovery rates (e.g., formation of gas caps, trapped water). With appropriate sequestration incentives and cost-effective supplies of $CO_2$, primary and secondary production techniques could be skipped entirely, potentially enhancing total oil production while sequestering large volumes of byproduct $CO_2$.

## Regional-scale $CO_2$ transportation

A large and integrated pipeline network is necessary to demonstrate an integrated CCUS system, connecting spatially dispersed, reliable, and market-viable supplies and demands of byproduct $CO_2$. Integrated pipeline networks minimize construction and operation costs for $CO_2$ transportation because economies of scale and utilization are be significant. [65] 7[51] Existing pipelines carry large volumes of extracted $CO_2$, such as the approximately 1000 km Cortez pipeline running from Colorado to West Texas for EOR; these pipelines are already at capacity. Industry has planned or established several basic $CO_2$ pipeline networks, including those that allow byproduct $CO_2$ suppliers to join the network.[66-68] Multiple efforts have developed detailed models to optimize integrated CCUS systems,[69-74] including examining an hypothetical pipeline network that links byproduct $CO_2$ from ethylene manufacturers with EOR reservoirs; $CO_2$ transport costs were estimated to be $5-6/t$CO_2$.[51] Such a pipeline system could be constructed with a combination of public (federal and/or state government) and private investment.[75] Obtaining right of ways (ROWs) can be barrier to constructing extensive pipeline systems, but policy and regulatory agencies could accelerate permitting processes, as has been done for renewable energy generation projects,[76, 77] and a combination of public and private investment,[75] could focus investment on ROWs that are robust to *a priori* uncertainties in where byproduct $CO_2$ may be captured and where it may be used.[77]

## Ethylene:$CO_2$-EOR

The challenge is to develop a large, commercially viable, and fully integrated system to build awareness and acceptance, reduce the cost of $CO_2$ capture through technological learning, and gain familiarity with byproduct $CO_2$ capture in business models. Byproduct $CO_2$ from ethylene manufacture is not presently used for $CO_2$-EOR, but the availability of large and clustered sources and the demand for $CO_2$ for EOR suggests that a commercially viable, large-scale integrated CCUS system could be deployed in the U.S. Gulf Coast and neighboring regions (Texas, Louisiana, Mississippi, New Mexico, Oklahoma, and Kansas). Specifically, ethylene manufacturing could be an appropriate case study because the facilities are much more geographically co-located than any other major $CO_2$ source (see the clustering column in Table 1; this would likely enable a lower-cost pipeline network to be constructed as well as potential collaboration among ethylene facilities). The region has experience with large-scale oil and gas operations, a history of ROW development, pipeline safety, and public acceptance, pipeline transportation and use of $CO_2$. Several oil fields in the region already use byproduct $CO_2$ from the chemical industry. These and other projects indicate the capacity to handle complex siting, liability, investment, and permitting issues. The preferred development pathway would be for ethylene byproduct $CO_2$ to initially complement the reliance on extracted $CO_2$ for EOR. The system would grow from individual ethylene facilities connected to individual EOR reservoirs to large-scale integrated clusters of multiple facilities. The CCUS pipeline network initiated with ethylene:$CO_2$-EOR could then be the backbone for a network that evolves to incorporate byproduct $CO_2$ from other industries and ultimately coal-fired and natural gas power plants. Our previous research has shown that it can be cost-effective to overbuild pipeline capacities and underutilize $CO_2$ transportation for a decade or more to enable the seamless integration of future $CO_2$ sources.[78] The experience with byproduct $CO_2$ capture could stimulate $CO_2$ capture investment on the numerous other byproduct $CO_2$ sources in the region—including fossil fuel power plants and oil refineries (Figure 5)—to eventually entirely displace extracted $CO_2$ for EOR.

Developing an ethylene:$CO_2$-EOR network would have significant challenges, notably the potential difference between a $CO_2$ capture and transport costs of \$50-60/t$CO_2$ and a byproduct $CO_2$-EOR purchase price of \$28-52/t$CO_2$. This difference could theoretically be profitable (-\$12/t$CO_2$), though even the most unprofitable difference (+\$32/t$CO_2$) only increases a \$1,000/t ethylene price by 3.2% (assuming that it is priced at marginal cost). Investment to provide byproduct $CO_2$ from ethylene facilities could also be a component of an initiative to reduce emissions from the industry, much like the approach in Houston, Texas that has targeted non-$CO_2$ emissions from a variety of chemical plants including facilities that crack ethane to produce ethylene.[79] A $CO_2$ tax or a cap-and-trade program that imposes a sufficient cost on emitting $CO_2$ could also encourage an integrated ethylene:$CO_2$-EOR system. A targeted $CO_2$ regulation—similar to the difference in treatment under proposed U.S. Environmental Protection Agency standards for $CO_2$ emissions from natural gas-fired turbines and coal-fired units[80]—could be implemented. And recently, Petra Nova has demonstrated the economic viability of installing post-combustion $CO_2$ capture technology at its 240 MW W.A. Parish (Thompsons, Texas) coal-fired generating station, where 1.4 Mt$CO_2$/yr is used to produce approximately 15,000 barrels of oil a day;[13, 14] through a partnership with the EOR operation, the $CO_2$ capture process is, without further subsidization or incentives, profitable. SaskPower's Boundary Dam carbon capture project has also successfully integrated $CO_2$ capture retrofit coupled with EOR.[11, 12]

$CO_2$ prices may fluctuate, and the competitive market price for $CO_2$ could decrease if the total supply of $CO_2$ from ethylene of other HVCP manufacturers increased faster than an increase in demand. But the possibility of collapsing the market price for $CO_2$ is low, in part because the unfulfilled demand for $CO_2$ for $CO_2$-EOR is larger than ethylene could ever supply.[28] Further, the market for $CO_2$ may not be perfectly competitive, in part because of the infrastructure needs to supply $CO_2$, and the present undersupply of $CO_2$ in the Permian Basin may be inflating the prices that EOR operators are securing in their contracts.[81] For an asset such as an oilfield to be considered a reserve, oil production must be feasible; the present undersupply of $CO_2$ for EOR would not be considered an undersupply if the economically viable production of the resource was sensitive to prices that change as a function of changes in $CO_2$ supply. In addition, $CO_2$ supply is only likely to exceed demand for EOR when the quantities of byproduct $CO_2$ from coal-fired and natural gas power plants are in the system. Such widespread $CO_2$ capture is only likely to occur in the long term and with credible and robust commitments to $CO_2$ emissions reductions, the regulation of which should also apply to emissions from HVCPs.

## Making CCUS a reality in North America and beyond

An ethylene:$CO_2$-EOR network would leverage favorable cost, engineering, and location factors in order to stimulate commercial-scale CCUS: clustered large $CO_2$ sources that could be captured at low cost, product prices that can absorb the increased costs with little if any impact on competitiveness, proximity to strong and consistent demand for $CO_2$, and a favorable business and regulatory environment. Such a network could reduce $CO_2$ emissions by as much as 50 $MtCO_2$/yr while producing 200 million bbl/yr of lower-carbon oil.[81] A 50 $MtCO_2$/yr system is equivalent to taking 10 million cars off the roads[82] and would be capturing, transporting, and storing more than twice the amount of byproduct $CO_2$ in CCUS projects worldwide (Figure 1).[21] Other HVCPs also have similarly favorable characteristics, including iron and steel, oil refining, and, although less clustered, ethanol (Table 1). The oil refining industry is particularly attractive because the industry is experienced with $CO_2$ removal through the oil-sweetening process, and oil refineries and oil fields are already connected by pipelines. Although the $CO_2$ capture cost at oil refineries ($19-96/$tCO_2$) could be higher than the $CO_2$ purchase price for EOR, recent research suggests that capturing $CO_2$ from the largest emitting components of the refining process is economically feasible.[83, 84] Principally, an integrated network based on ethylene or other HVCP byproduct $CO_2$ would provide a visible and economically viable CCUS demonstration that can increase public awareness and acceptance of CCUS as a climate change mitigation technology.

An HCVP:$CO_2$-EOR system could serve as a point of departure for other projects in North America and beyond. For example, the $CO_2$ footprint of Alberta oil sands production, which has a wells-to-tank $CO_2$ intensity 70-110% higher than typical U.S. transportation fuels,[85] could be reduced by using the $CO_2$ in nearby EOR fields.[86] Shale gas, which has led to a low-cost lower-carbon energy boom in the United States, could also provide a large potential for $CO_2$ injection/fracturing[87, 88] and storage[88, 89] from commercial-scale $CO_2$ emission sources. France, whose $CO_2$ emissions are largely from non-electricity sources, also provides a relevant case study for developing CCUS using HCVPs.[77] China also has substantial opportunities for HCVP byproduct $CO_2$-EOR systems. China's ethylene production is projected to approximately double to 25.5 Mt/yr by 2015,[90, 91] and China is actively developing and deploying coal-to-liquids technology. The goal of this development is to increase oil production, but the inherent gasification process produces a stream of almost pure $CO_2$[92] that could be used for $CO_2$-EOR. A Chinese coal-to-liquids:$CO_2$-EOR system could stimulate commercial-scale CCUS without external incentives.

Overall, a CCUS network based on byproduct $CO_2$ from HVCPs could reduce $CO_2$ emissions in the near term while leveraging the market viability of $CO_2$ capture when implemented on HVCP facilities and when the captured byproduct $CO_2$ is used for EOR. Deploying this large-scale system is potentially possible in the U.S. Gulf Coast, where numerous large and clustered sources of $CO_2$ as a byproduct of ethylene production as well as EOR opportunities are present. Such a visible integrated system can increase public awareness and demonstrate an approach that reduces $CO_2$ emissions while complementing existing CCUS technology development strategies.

## References


1. Nordhaus, W. D., The climate casino: Risk, uncertainty, and economics for a warming world. Yale University Press: 2013.
2. Metz, B.; Davidson, O.; De Coninck, H.; Loos, M.; Meyer, L. IPCC special report on carbon dioxide capture and storage; Working Group III of the Intergovernmental Panel on Climate Change: Cambridge, 2005.
3. Stauffer, P. H.; Keating, G. N.; Middleton, R. S.; Viswanathan, H. S.; Berchtold, K. A.; Singh, R. P.; Pawar, R. J.; Mancino, A., Greening Coal: Breakthroughs and Challenges in Carbon Capture and Storage. Environmental Science & Technology 2011, 45, (20), 8597-8604.
4. Middleton, R. S.; Keating, G. N.; Stauffer, P. H.; Jordan, A. B.; Viswanathan, H. S.; Kang, Q. J.; Carey, J. W.; Mulkey, M. L.; Sullivan, E. J.; Chu, S. P.; Esposito, R.; Meckel, T. A., The cross-scale science of CO2 capture and storage: from pore scale to regional scale. Energy & Environmental Science 2012, 5, (6), 7328-7345.
5. IEA Tracking Clean Energy Progress 2013; IEA: Paris, 2013.
6. GEA, Global Energy Assessment - Toward a Sustainable Future. Cambridge University Press, Cambridge, UK and New York, NY, USA and the International Institute for Applied Systems Analysis, Laxenburg, Austria, 2012.
7. Conti, J.; Holtberg, P.; Beamon, J.; Napolitano, S.; Schaal, A., Annual Energy Outlook 2013 with Projections to 2040. US Energy Information Admin., Washington, DC, Rep. EIA-0383 2013.
8. EIA Electricity. http://www.eia.gov/electricity/ (November, 2013).
9. Shackley, S.; Verma, P., Tackling CO2 reduction in India through use of CO2 capture and storage (CCS): Prospects and challenges. Energy Policy 2008, 36, (9), 3554-3561.
10. Middleton, R. S.; Keating, G. N.; Viswanathan, H. S.; Stauffer, P. H.; Pawar, R. J., Effects of geologic reservoir uncertainty on CO2 transport and storage infrastructure. International Journal of Greenhouse Gas Control 2012, 8, 132-142.
11. MIT Carbon Capture and Sequestration Project Database. https://sequestration.mit.edu/tools/projects/index.html (February, 2015).
12. SaskPower Boundary Dam carbon capture project. http://saskpowerccs.com/ccs-projects/boundary-dam-carbon-capture-project/ (February, 2015).
13. Armpriester, A.; Smith, R.; Scheriffius, J.; Smyth, R.; Istre, M. WA Parish Post-Combustion CO {sub 2} Capture and Sequestration Project Phase 1 Definition; Petra Nova Parish Holdings Llc: 2014.
14. NETL Recovery Act: W.A. Parish Post-Combustion CO2 Capture and Sequestration Project. http://www.netl.doe.gov/research/proj?k=FE0003311&show=cdc (December, 2014).
15. Esposito, R. A.; Monroe, L. S.; Friedman, J. S., Deployment models for commercialized carbon capture and storage. Environmental Science and Technology 2011, 45, 139-146.

16. Parker, M.; Valencia, J.; Northrop, S.; Foglesong, B.; Duncan, W. In CO2 Management at ExxonMobil's LaBarge Field, Wyoming, USA, International Petroleum Technology Conference, 2009; 2009.
17. Statoil Sleipner Vest. http://www.statoil.com/en/technologyinnovation/protectingtheenvironment/carboncaptureandstorage/pages/carbondioxideinjectionsleipnervest.aspx (December, 2010).
18. Global Carbon Capture and Storage Institute Gorgon Carbon Dioxide Injection Project. http://www.globalccsinstitute.com/projects/12416 (May, 2013).
19. Petroleum Technology Research Centre Weyburn-Midale research project. http://www.ptrc.ca/weyburn_overview.php (January 12, 2011).
20. MGSC Midwest Geologic Sequestration Consortium Project. http://sequestration.org/ (May, 2013).
21. GCCSI Large-scale Integrated CCS Projects. http://www.globalccsinstitute.com/projects/browse (August, 2013).
22. Reiner, D.; Curry, T.; de Figueiredo, M.; Herzog, H.; Ansolabehere, S.; Itaoka, K.; Akai, M.; Johnsson, F.; Odenberger, M., An international comparison of public attitudes towards carbon capture and storage technologies. NTNU [2006]. URL *http://www*. ghgt8. no 2006.
23. Bielicki, J., M.; Middleton, R. S.; Levine, J. S.; Stauffer, P. H., An Alternative Pathway for Stimulating Regional Deployment of Carbon Dioxide Capture and Storage. Energy Procedia 2015, In press.
24. NETL National Carbon Sequestration Database and Geographic Information System (NATCARB). http://www.netl.doe.gov/technologies/carbon_seq/natcarb/ (August, 2013).
25. EPA Emissions & Generation Resource Integrated Database (eGRID). http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html (August, 2013).
26. Lazard Levelized cost of energy analysis - version 6.0; 2012 (https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2012/20121221/20121221%20PAC%20Supplemental%20Levelized%20Cost%20of%20Energy%20Analysis.pdf).
27. Rubin, E. S.; Chen, C.; Rao, A. B., Cost and performance of fossil fuel power plants with $CO_2$ capture and storage. Energy Policy 2007, 35, 4444–4454.
28. GCCSI The Global Status of CCS: 2012; Canberra, Australia, 2012 (http://www.globalccsinstitute.com/publications/global-status-ccs-2012).
29. Rubin, E. S.; Zhai, H., The Cost of Carbon Capture and Storage for Natural Gas Combined Cycle Power Plants. Environmental Science & Technology 2012, 46, (6).
30. Azar, C.; Lindgren, K.; Larson, E.; Möllersten, K., Carbon capture and storage from fossil fuels and biomass–Costs and potential role in stabilizing the atmosphere. Climatic Change 2006, 74, (1-3), 47-79.
31. EIA Refinery Receipts of Crude Oil by Method of Transportation. http://www.eia.gov/dnav/pet/pet_pnp_caprec_dcu_nus_a.htm (August, 2013).

32. Kelly, T. D.; Matos, G. R. Historical Statistics for Mineral and Material Commodities in the United States; USGS: 2013 (http://minerals.usgs.gov/ds/2005/140/).
33. True, W. R., Global ethylene capacity continues advance in 2011. Oil & gas journal 2012, 110, (7), 78-84.
34. ICIS ICIS pricing. http://www.icispricing.com/ (May, 2013).
35. RFA, Accelerating industry innovation: 2012 ethanol industry outlook. Renewable Fuels Association. In Renewable Fuels Association: 2012.
36. Nasdaq Ethanol Futures Prices. http://www.nasdaq.com/markets/ethanol.aspx (August, 2013).
37. EIA Natural gas processing plant data now available. http://www.eia.gov/todayinenergy/detail.cfm?id=8530 (August, 2013).
38. EIA Natural Gas. http://www.eia.gov/naturalgas/ (August, 2013).
39. Romero, S., 2 Industry Leaders Bet on Coal but Split on Cleaner Approach. New York Times 2006.
40. Hertzler, M. J.; Koeller, M. N., Who Pays for Carbon Costs-Uncertainty and Risk in Response to the Current Patchwork of Carbon Regulation for Public Utilities. Wm. Mitchell L. Rev. 2009, 36, 904.
41. IEA, Tracking Industrial Energy Efficiency and CO2 Emissions. OECD Publishing: 2007.
42. LIPPE, D., 2012 ethylene production bounces back; turnarounds in early 2013 to curb output. Oil & gas journal 2013, 111, (3).
43. IEA, Prospects for Carbon Dioxide Capture and Storage. OECD Publishing: 2004.
44. IPCC, IPCC guidelines for national greenhouse gas inventories. IGES, Japan 2006.
45. Chakravarti, S.; Gupta, A.; Hunek, B. In Advanced technology for the capture of carbon dioxide from flue gases, First National Conference on Carbon Sequestration, Washington, DC, 2001; 2001; pp 15-17.
46. Ren, T.; Patel, M.; Blok, K. In Energy efficiency and innovative emerging technologies for olefin production, European Conference on Energy Efficiency in IPPC-Installations in Vienna, Austria on October, 2004; 2004; pp 21-22.
47. ICIS ICIS pricing. http://www.icispricing.com/ (May 20th, 2013).
48. NETL Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution; 2010 (http://www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2_EOR_Primer.pdf).
49. Oil and Gas Journal Survey: Miscible CO2 now eclipses steam in US EOR production. http://www.ogj.com/articles/print/vol-110/issue-4/general-interest/special-report-eor-heavy-oil-survey/survey-miscible-co-2.html (May, 2013).
50. Hargrove, B.; Melzer, L.; Whitman, L. In A Status Report on North American CO2 EOR Production and CO2 Supply, 16th Annual CO2 Flooding Conference, Midland, TX, 2010; 2010.
51. Middleton, R. S., A new optimization approach to energy network modeling: anthropogenic CO2 capture coupled with enhanced oil recovery. International Journal of Energy Research 2013, DOI: 10.1002/er.2993.

52. Middleton, R. S.; Clarens, A. F.; Liu, X.; Bielicki, J. M.; Levine, J. S., CO2 deserts: Implications of existing CO2 supply limitations for carbon management. Environmental Science & Technology 2014.
53. Hussain, D.; Dzombak, D. A.; Jaramillo, P.; Lowry, G. V., Comparative lifecycle inventory (LCI) of greenhouse gas (GHG) emissions of enhanced oil recovery (EOR) methods using different CO< sub> 2</sub> sources. International Journal of Greenhouse Gas Control 2013, 16, 129-144.
54. NETL Improving Domestic Energy Security and Lowering CO2 Emissions with "Next Generation" CO2-Enhanced Oil Recovery (CO2-EOR) DOE/NETL-2011/1504; 2011.
55. Tracy, K. In Anthropogenic CO2 as a CCUS Commodity 12th Annual Conference on Carbon Capture, Utilization & Sequestration, Pittsburgh, PA, 2013; Pittsburgh, PA, 2013.
56. Wang, M. Q.; Huang, H. S. A full fuel-cycle analysis of energy and emissions impacts of transportation fuels produced from natural gas; Argonne National Lab., IL (US): 2000.
57. Unnasch, S.; Pont, J., Full Fuel Cycle Assessment: Well-to-wheels Energy Inputs, Emissions, and Water Impacts: Preparation for the AB 1007 (Pavley) Alternative Transportation Fuels Plan Proceeding. California Energy Commission: 2007.
58. NGVAmerica NGVs and the Environment. http://www.ngvc.org/about_ngv/ngv_environ.html (January, 2014).
59. Wang, M. Q.; Han, J.; Haq, Z.; Tyner, W. E.; Wu, M.; Elgowainy, A., Energy and greenhouse gas emission effects of corn and cellulosic ethanol with technology improvements and land use changes. Biomass and Bioenergy 2011, 35, (5), 1885-1896.
60. Wang, M.; Wu, M.; Huo, H., Life-cycle energy and greenhouse gas emission impacts of different corn ethanol plant types. Environmental Research Letters 2007, 2, (2), 024001.
61. Samaras, C.; Meisterling, K., Life cycle assessment of greenhouse gas emissions from plug-in hybrid vehicles: Implications for policy. Environmental Science & Technology 2008, 42, (9), 3170-3176.
62. Dai, Z.; Middleton, R. S.; Viswanathan, H. S.; Fessenden-Rahn, J.; Bauman, J.; Pawar, R. J.; Lee, S.-Y.; McPherson, B., An Integrated framework for optimizing CO2 sequestration and enhanced oil recovery. Environmental Science & Technology Letters 2013.
63. King, C. W.; Gülen, G.; Cohen, S. M.; Nuñez-Lopez, V., The system-wide economics of a carbon dioxide capture, utilization, and storage network: Texas Gulf Coast with pure CO2-EOR flood. Environmental Research Letters 2013, 8, (3), 034030.
64. Jarrell, P. M.; Fox, C. E.; Stein, M. H.; Webb, S. L., Practical aspects of $CO_2$ flooding. Society of Petroleum Engineers: Richardson, TX, 2002.
65. Kuby, M. J.; Middleton, R. S.; Bielicki, J. M., Analysis of cost savings from networking pipelines in CCS infrastructure systems. In 10th International Conference on Greenhouse Gas Control Technologies, Gale, J.; Hendriks, C.; Turkenberg, W., Eds. 2011; Vol. 4, pp 2808-2815.
66. ICO$_2$N Carbon Dioxide Capture and Storage: A Canadian Clean Energy Opportunity; 2009 (http://www.ico2n.com/wp-content/uploads/2010/07/ICO2N-Report_09_final2.pdf); p 20.

67. Denbury Operations: $CO_2$ pipelines. http://www.denbury.com/index.php?id=18 (May, 2011).
68. Kinder Morgan CO2 transportation. http://www.kindermorgan.com/business/co2/transport_cortez.cfm (August, 2013).
69. Middleton, R. S.; Bielicki, J. M., A scalable infrastructure model for carbon capture and storage: SimCCS. Energy Policy 2009, 37, (3), 1052-1060.
70. Keating, G. N.; Middleton, R. S.; Stauffer, P. H.; Viswanathan, H. S.; Letellier, B. C.; Pasqualini, D.; Pawar, R. J.; Wolfsberg, A. V., Mesoscale Carbon Sequestration Site Screening and CCS Infrastructure Analysis. Environmental Science & Technology 2011, 45, (1), 215-222.
71. van den Broek, M.; Brederode, E.; Ramirez, A.; Kramers, L.; van der Kuip, M.; Wildenborg, T.; Turkenburg, W.; Faaij, A., Designing a cost-effective $CO_2$ storage infrastructure using a GIS based linear optimization energy model. Environmental Modelling & Software 2010, 25, (12), 1754-1768.
72. Morbee, J.; Serpa, J.; Tzimas, E., Optimised deployment of a European CO2 transport network. International Journal of Greenhouse Gas Control 2012, 7, (0), 48-61.
73. Mendelevitch, R.; Herold, J.; Oei, P.-Y.; Tissen, A., CO2 Highways for Europe: Modelling a Carbon Capture, Transport and Storage Infrastructure for Europe. CEPS Working Document No. 340 2010.
74. Klokk, O.; Schreiner, P. F.; Pages-Bernaus, A.; Tomasgard, A., Optimizing a $CO_2$ value chain for the Norwegian Continental Shelf. Energy Policy 2010, 38, (11), 6604-6614.
75. Bielicki, J. M. Integrated systems analysis and technological findings for carbon capture and storage deployment. Harvard University, 2009.
76. Executive Office of the President, The President's climate action plan. In 2013.
77. Bielicki, J. M.; Calas, G.; Middleton, R. S.; Ha-Duong, M., National corridors for climate change mitigation: managing industrial CO2 emissions in France. Greenhouse Gases: Science and Technology 2013, n/a-n/a.
78. Middleton, R. S.; Kuby, M. J.; Wei, R.; Keating, G. N.; Pawar, R. J., A dynamic model for optimally phasing in CO2 capture and storage infrastructure. Environmental Modelling & Software 2012, 37, 193-205.
79. Frazier, R. R., Houston cleaning up pollution by going after ethane cracker emissions. Observer-Reporter 2013.
80. EPA EPA Proposes Carbon Pollution Standards for New Power Plants. http://yosemite.epa.gov/opa/admpress.nsf/0/da9640577ceacd9f85257beb006cb2b6!OpenDocument (November, 2013).
81. Godec, M. L. Sectoral Assessment: CO2 Enhanced Oil Recovery; United Nations Industrial Development Organization: Vienna, Austria, 2011 (http://cdn.globalccsinstitute.com/sites/default/files/publications/15676/global-technology-roadmap-ccs-industry-sectoral-assessment-co2-enhanced-oil-recovery.pdf).
82. EPA Greenhouse Gas Emissions from a Typical Passenger Vehicle 2011 (http://www.epa.gov/otaq/climate/documents/420f11041.pdf).

83. Middleton, R. S.; Bielicki, J. M.; Keating, G. N.; Pawar, R. J., Jumpstarting CCS using refinery CO2 for enhanced oil recovery. In 10th International Conference on Greenhouse Gas Control Technologies, Gale, J.; Hendriks, C.; Turkenberg, W., Eds. 2011; Vol. 4, pp 2185-2191.
84. Hallerman, T., Pilot Results: Oxy-firing on refinery viable. GHGNews September, 2013.
85. Lattanzio, R. K. In Canadian oil sands: life-cycle assessments of greenhouse gas emissions, 2012; Congressional Research Service, Library of Congress: 2012.
86. Middleton, R. S.; Brandt, A. R., Using Infrastructure Optimization to Reduce Greenhouse Gas Emissions from Oil Sands Extraction and Processing. Environmental Science & Technology 2013, 47, (3), 1735-1744.
87. Wang, H.; Li, G.; Shen, Z., A Feasibility Analysis on Shale Gas Exploitation with Supercritical Carbon Dioxide. Energy Sources, Part A: Recovery, Utilization, and Environmental Effects 2012, 34, (15), 1426-1435.
88. Middleton, R. S.; Carey, J. W.; Currier, R. P.; Hyman, J. D.; Kang, Q.; Karra, S.; Jiménez-Martínez, J.; Porter, M. L.; Viswanathan, H. S., Shale gas and non-aqueous fracturing fluids: opportunities and challenges for supercritical $CO_2$. Applied Energy 2015, In review.
89. Tao, Z.; Clarens, A. F., Estimating the carbon sequestration capacity of shale formations using methane production rates. Environmental Science & Technology 2013.
90. Juan, D., China's ethylene production capacity to increase. China Daily 2012.
91. ICIS China invents and reinvents coal to chemicals. http://www.icis.com/Articles/2012/04/16/9549986/china+invents+and+reinvents+coal+to+chemicals.html (August, 2013).
92. Steynberg, A. P.; Nel, H. G., Clean coal conversion options using Fischer–Tropsch technology. Fuel 2004, 83, (6), 765-770.